# CALIFORNIA'S ELECTRICITY OPTIONS AND CHALLENGES

# REPORT TO THE GOVERNOR

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# I. CALIFORNIA'S ELECTRIC SYSTEM: WHERE WE ARE AND HOW WE GOT HERE

**California's electric system is in trouble. To understand why, we need to know how it operates and how comprehensive changes in the l990s affected its operation.**

## ***1. The Electric System in California Is Interconnected***

The State's electric system has three major components:

? Generation – Generation refers to the production of electricity at power plants or other facilities. California has about 1,000 generation facilities with 55,500 MW of capacity, including those run by gas and oil, nuclear power, hydro, biomass, wind, solar and cogeneration.[1] The State is able to import an additional 8,000 MW and, of these, about 4,500 MW are under contract as "firm" supplies.[2]

? Transmission – the wires that run from generators to carry power throughout the State to distribution facilities. California has about 40,000 miles of power lines that connect utilities to the national and international electric power grid.

? Distribution – the wires and related facilities that run from customer premises to transmission substations (the sites where high voltage power is stepped down so that it can be delivered to customers on the distribution system) ;

The system's components are highly interrelated, economically and operationally. California can relieve supply problems by constructing new generation plants or transmission facilities. Transmission facilities are a key element of the structure, because they tie together the large power plants, often in remote locations, to the load centers where electricity is consumed. In a competitive system, the ability of generation sellers and generation buyers to interact is mediated by the transmission system.
If transmission transfer capacity is inadequate, the ability of loads to get imported power is reduced, and the ability of local generators to raise prices through the exercise of their market power is enhanced. California has a demonstrated need for transmission upgrades for both reasons.

As the chart to the right shows, California's electricity comes from many different sources, some more costly than others, and some cleaner.

## *2. Regulation of California's Electric System Is No Longer Integrated*

Historically, California utilities owned and operated all elements of the State's electric system. The PUC regulated the entire system[3] of utility generation, distribution and transmission through its control of retail rates. The PUC also regulated service reliability, utilities' dealings with their customers, and the availability of different types of electric service. The PUC was responsible for – and had the tools to police -- the utilities' service to consumers. FERC regulated wholesale transmission rates and power transactions between utilities and between utilities and generators. But because utilities owned most power plants, and sold power directly to the customer, FERC did not set California power rates. Historically, the PUC and the FERC had a complementary role in setting wholesale rates for non-utility power producers, called "qualifying facilities."

For more than fifty years before 1996, the structure of the California electricity industry changed little. Investor-owned utilities owned and operated power plants and wires, and they charged retail electricity rates as set by the PUC. As the chart below shows, the vast majority of power used in California was produced either by a for-profit or municipal utility, both regulated by public entities. Transactions between utilities and with other States were overseen by the FERC. Both the PUC and the FERC were required by law to set "just and reasonable" rates. They did so by basing rates on demonstrated costs and acting as a brake on price run-ups. But in the early 1990's rising retail prices and a philosophical shift away from cost-of-service regulation and toward competition led to calls for reform.

? **Before the 1980s.** Investor-owned utilities planned, built, owned, and operated distribution, transmission, and power plants under PUC supervision. Prices for energy were set according to the costs of running power plants, and these costs were scrutinized by the PUC to ensure reasonable prices. Utilities were held accountable for reliability by the PUC and the public, and utilities had strong incentives to plan and operate their power plants and other facilities to give highly reliable service. During this period, the utilities pursued investments in large power plants and nuclear facilities.

? **The 1980s.** In the l980s, utilities also administered energy efficiency and conservation programs using ratepayer funds under PUC supervision. State energy planners and regulators balanced supply and demand through Integrated Resource Planning, building new power plants when needed but investing in conservation and energy efficiency to minimize the need for costly new plants. By this time, nuclear plants were built and running, and the cost of producing that power increased utility rates. Late in the decade, utility rates were driven up further by higher fuel prices and policies that encouraged QFs to build new private, non-utility power plants.

As the chart to the right shows, during this period power plants were largely owned by utilities or public agencies, and their rates were overseen by state or local government.

- **The Early l990s**. In the early 1990s, the PUC's and past administrations' commitment to integrated resource planning waned. The PUC's policy increasingly emphasized competitive provision of power. It used a bidding process[4] to choose new power plants to meet projected demand, but little or no new capacity was actually built before that process was superseded by the mid-90s, policy shift away from cost-of-service regulation and toward reliance on pure market forces. The chart on the following page shows who owns power plants in California now.

In 1994, the PUC recommended fundamental structural reform that would move substantial regulatory authority to the federal government. In l995, the PUC made official its commitment to competitive market models when it issued an order directing the utilities to "unbundle" their integrated systems[5] and in l996, AB 1890[6], responded to and shaped the actions already underway at the PUC.

In sum, the PUC direction, as shaped by AB 1890:

- Transferred pricing of California's electricity generation to the FERC by creating the California Power Exchange, a private nonprofit organization which would set wholesale sales of electricity;
- Created incentives for utilities to sell their generation facilities to unregulated private power companies;
- Transferred operational control of the utility-owned transmission system to the ISO, a private nonprofit organization which would manage the transmission system and its day-to-day operations under FERC oversight;
- Let the utilities retain ownership and control of the distribution system;
- Set rates in a way that accelerated payoffs of the capital costs of utility power plants by permitting the utilities to "freeze" artificially high rates and use revenues exceeding costs to pay down capital investment. The amount used for this purpose is listed as a "CTC"[7] charge on every Californian's electric bill.
- Provided that the rate freeze would end when the capital costs of utility generation assets have been recovered or at the end of a 2001, whichever occurs first. The rate freeze ended for SDG&E in mid-l999[8]; it remains in place for PG&E and Edison.

Every constituency group endorsed AB 1890, except one consumer group that took no position. California lawmakers and their constituencies were optimistic that the new model would bring prices down and assure safe, reliable power.

## ***3. Purchases and Sales of Power Under the New Structure***

The new system of buying and selling power, and the rules that govern those sales and purchases, is extraordinarily complex. Simply stated, a day in advance, participating generators bid power into the wholesale market auction, conducted by the PX and their counterpart buyers, estimate and order the power needed to meet California's electricity demands. On the basis of hourly supply and demand bids and orders, the PX sets the price to be paid to all power sellers at the highest amount bid for that hour, even if some sellers would have sold power at a lower price. The ISO then directs the flow of electricity throughout the State. When supply purchased in the PX market is less than the State's demand for electricity, the ISO makes up the difference by purchasing enough electricity to balance the load and meet specified "reserve" levels.

The Independent System Operator administers a graduated system of increasing alerts to maintain operating reserves – the buffer capacity needed at all times to keep the electric system stable and functioning. When forecasted reserves for the next day fall below 7%, the ISO issues an Alert, and generators are asked to increase their power bids into the market. When forecasted reserves for the current day fall below 7%, the ISO issues a Warning, and the ISO begins buying supplies directly. When actual reserves fall below 7%, then 5%, then 1.5% the ISO issues first a Stage 1 Emergency (public appeals and other measures to increase supply and decrease demand), then a Stage 2 Emergency, (interruptible customers are curtailed), and finally a Stage 3 Emergency, the highest level, under which firm customers (including residential and commercial) are blacked out to keep the system from crashing.

The ISO purchases "ancillary services" – generation products needed to enable it to instantaneously balance load by ramping generators up and down – that include both the capacity to produce electricity, and the actual production. There are a number of "auctions" for ancillary services into which generators can bid under current rules; in addition, schedule coordinators (SCs) can adjust their schedules to enable the ISO to balance the system. In addition, the ISO has signed long term "reliability- must-run" contracts with some generators whose power is used to keep the transmission system stabilized. These R-M-R contracts provide a degree of control comparable to the former utility integrated ownership.

The ISO limits the top price purchasers will be charged for electricity with "price caps" approved by the FERC through the tariff process. Wholesale price caps limit the market's ability to drive prices up during periods of short supply. The use of price caps recognizes the potential for sellers' market power or customers' inelastic demand to drive up prices.

Currently, the law requires that California electric utilities, which serve the vast majority of California customers, purchase all of their power through the ISO and the PX. However, individual (usually large) customers and marketers may purchase power outside the PX by signing "bilateral" contracts with marketers or generators. The ISO's centralized system still directs the flow of electricity, but prices and service conditions are established by private contract.

## ***4. California in the National Context***

California was the first state in the nation to create a separate independent system operator – the ISO – to control utility-owned transmission facilities. California moved first and furthest in divesting the utilities of their power plants. It created an exchange – the PX – to run wholesale power auctions and shape wholesale power products, like futures. The separation of the power sales function and the transmission control system function into two separate organizations is a distinguishing characteristic of California's experiment. The separation of these functions also complicates the operation of California's wholesale electricity market.

Several other states have followed California in designing their electricity industries with ISOs that are regulated not by State or local authorities, but by the FERC. However, California is the only state with an ISO comprised of stakeholders rather than an ISO that is a public agency.

Twenty-five states have not yet restructured their electric industries, apparently awaiting the results of changes in California and Northeastern States. In addition, municipal utilities in California have been cautious to join the new statewide system. Although they have coordinated some of their system operations with the ISO, the PX and the State's other utilities, municipal power companies have retained their power plants and control of their transmission systems. This control has protected customers of municipal utilities—like the Los Angeles Department of Water and Power—from the price shocks and supply shortages that have occurred in other parts of the State this summer.

California's choice of restructuring plans has made a difference in California prices and supply conditions, even though California is part of a tightly interconnected grid that courses through several states in the Western Region. California participates in the Western Systems Coordinating Council, a voluntary organization that coordinates the activities of the "control areas" that make up the grid. The WSCC establishes reliability standards, such as operating reserve requirements, that protect the larger system for all interconnected participants.

The California ISO is the largest control area. It buys and sells enormous quantities of electricity, dispatching power from plants and operating the California transmission system. Unlike the other utilities that participate in the WSCC, the ISO is neither a governmental body nor a state-regulated utility. The

California ISO has no responsibility to California consumers.  Indeed, it seeks to control the transmission system in several states as a regional operation.

## Conclusions

Over the past twenty years California has transformed its electric system from one that was integrated and highly regulated to one that is unbundled and increasingly subject to competitive markets and federal oversight.  Although the state retains regulatory control over utility distribution systems, the FERC regulates the transmission system operations and transmission rates.  The FERC also regulates the terms and conditions of most power trades in California because most are now wholesale transactions rather than retail transactions which would be subject to state regulatory oversight.  In addition, power sales and transmission are controlled mainly by two private, nonprofit organizations that have no duty to serve California's public.

Under California's new system, California power purchasers so far this summer have paid much more for power than in the past and the system has been more vulnerable to supply shortages than ever before.

# II. THE LESSONS OF SPRING 2000

The events giving rise to this Report started with ISO calls for widespread interruption of industrial and other large customers on May 22, 2000, and the imposition of rolling blackouts in the Bay Area on June 14, 2000. Beginning in May 2000, costs for power in all regions and economic sectors of California increased by billions of dollars. On several days in the second quarter of the year, reliability was significantly compromised. The appearance that reliability has been compromised makes all the more distressing the huge run-up in prices – Californians are paying a lot more for a lot less, in terms of service.

***1. Coordination Problems Occurred in May, Triggering Unnecessary Power Interruptions***.

On May 22, 2000, the weather was hot in Northern California. The ISO anticipated an electricity shortage and declared a Stage 2 emergency at 11:40 a.m. It called for utilities to curtail service to several hundred large customers.[9] A Stage 2 emergency means that operating reserves are less than 5% of expected load; curtailment means that some customers, must reduce their consumption and shut down operations of necessary. These customers who are paid in advance for this responded promptly. Some sent their employees home. But it very quickly developed that the ISO had made a calculation error, losing track of approximately 1500 MW[10] of available power, and leaving that power out of its calculation.

On June 14, PG&E was required to intentionally interrupt nearly 100,000 customers (residential and small business) for the first time in its history. This remarkable event was not related to insufficient supply in the ISO control area as a whole. Rather, it was related to grid instability in the Bay area. The transmission grid operates at a load level of 230,000 volts, with small deviations. If supply and demand get too far out of balance, a portion, then the entire system can crash, possibly spreading throughout the interconnected grid in the West.

The Bay area grid instability was related to high loads and short supplies in that area, which could not be relieved given the design of the transmission system. It was exacerbated by the fact that the evening before, instability was created by generator decisions to generate energy without notifying the ISO Generators created these deviations in order to be paid a higher price within the ISO Control Area, and these deviations caused less than optimal voltage stability on its system.[11] The ISO became aware of this instability on June 13; the stage was set for the following day.

On June 14 the Bay Area suffered unusually hot weather for June, with San Francisco peaking at 103 degrees. Hot weather contributed directly to a record-setting peak load for June of 43,300 MW, system wide. PG&E peaked at 23,361 MW[12], not counting the customers interrupted.

On June 14, import capacity on the transmission system was limited, in order to keep the voltage levels on the grid stable. These import limitations reflected both technical constraints in Northern California and events outside the state. The loss of generation in the Northwest and work being done by Bonneville Power Administration on the British Columbia Hydroelectric Tie limited California's ability to import power.

Voltage instability related to gaming on the previous day, import limitations, power plants out, and record temperatures set the stage for disaster on June 14, 2000. At 7:30 a.m. the CAISO announced that it would request PG&E to curtail 500 MW of interruptible customers beginning at 1200 hours to help correct voltage problems. Reactive support at the transmission and distribution levels was also required of PG&E and the municipalities (Silicon Valley Power, Northern California Power Agency (NCPA), Alameda and Palo Alto).

The critical point below which a system crash becomes imminent is 225,000 volts. Late in the morning, the ISO determined that firm load dropping was imminent and requested PG&E to man all substations. In order to avoid a voltage crash in the Bay Area, the Newark Substation had to maintain a voltage of 228 kV. At 1313 hours, the Newark Substation dropped to 227,000 volts and headed toward 226,000 volts. This triggered the ISO's request for firm load shedding by PG&E. The following blocks were shed:

| Block Number | Duration of Outage | Number of Customers[13] | Number of MW |
|---|---|---|---|
| 1A | 1313 to 1435 | 33,763 | 143.9 |
| 1B | 1430 to 1535 | 17,616 | 132.1 |
| 1D | 1530 to 1635 | 9,586 | 29.4 |
| 2A | 1530 to 1635 | 36,064 | 115.5 |
| **Total** | **1313 to 1635** | **97,029** | **420.9** |

Once Block 1A[14] was shed, by contract NCPA shed 3 MW at Palo Alto and 1 MW at Alameda. In a cooperative action, Silicon Valley Power offered to interrupt its non-firm customers, totaling 5 MW beginning at 1400 hours. In order to reduce further curtailments, the ISO loaded key 500/230 kV transformers and transmission lines either near or exceeding their ratings. The firm load shed caused voltage levels to stabilize and averted a wider event.

The ISO issued a Stage 1 Emergency Notice throughout its system, due to a projected operating reserve of 5.3 percent beginning at 1:00 p.m., remaining in effect until 2000 hours. All firm load was restored by 4:35 p.m. with interruptible load restored at 6 p.m.

## ***2. Retail Prices for Electricity Increased Substantially***

In the week, of June 11-15, purchasers of California power spent over $1 billion to buy electricity, one eighth of their spending for all of 1999.[15] The effects of these price increases on customers depend on their choice of electricity supplies. Retail customers of Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (Edison) are temporarily protected from the impact of rate spikes caused by direct exposure to high wholesale prices. Customers of municipal utilities may face higher prices, unless their governing bodies have deferred rate increases. Retail customers of non-utility electricity marketers, including renewable energy customers who have opted for direct access, may also have higher bills if their electricity rate is set as some percentage of the "PX price." Anecdotal evidence suggests that this is the case.

Because SDG&E is no longer subject to a retail price freeze, its customers' electric bills for June service more than doubled, as the chart below illustrates. The portion of retail customers' bills that goes to pay for electricity[16] increased almost 300% (from roughly 5 cents to 15 cents). As a result, SDG&E's total rates for June are twice the national average for residential consumers. The charts below compare residential rates and residential bills for SDG&E, PG&E and Edison over the past decade.

The rise in bills experienced in San Diego prefigure rises that will eventually come to other California customers.  The high residential electricity rates demonstrated in the chart below will hit other customers unless something is done.

Currently, SDG&E may "levelize" its retail customers' liability for these wholesale electricity costs by spreading out the high electricity payments over a future period, pursuant to PUC authorization.  Generally, however, the PUC is limited in what it can do to relieve customers' liability for these wholesale costs.  The federal "filed rate doctrine" requires States to pass through to utility customers the costs of electricity that are purchased subject to federal tariffs.[17]  SDG&E's purchases from the ISO and PX are federally tariffed.  Thus, the FERC ultimately controls how much SDG&E pays for wholesale power.  Whatever SDG&E pays for wholesale power, if allowed under a federal tariff, must by federal mandate be passed through to San Diego utility customers.  The PUC may, however, inquire whether SDG&E's purchasing strategies were reasonable and resulted in reasonable rates.  The PUC may exclude from retail rates recovery of costs determined to have been imprudently incurred.

The San Diego price spikes, impose particular burdens on fixed and low-income customers.  The PUC sets a discounted rate for low-income customers by statute.  Currently, the PUC requires that all utilities offer a 15% discount for low-income customers under the "CARE" program.[18]  This discount is clearly not a complete solution for customers whose bills have recently doubled.

### *3. Wholesale Prices Increased Substantially*

This summer's high electricity bills result from increased wholesale prices. Wholesale prices for May and June 2000 are many times higher than for May and June 1999.

The price increase is not explainable by increased costs, weather, volumes or even the existence of a much higher wholesale price cap, in 2000. A comparison of June 29, 1999 to June 29, 2000, both relatively hot weekdays, illustrates the magnitude of the run-up in wholesale prices. Peak loads on the ISO system were comparable: 40,443 megawatts at 4 p.m. in 1999; 41,606 at 4 p.m. in 2000, a difference of less than 3 percent. Sales volumes in the PX day ahead market were also comparable, but prices in the day ahead market were much higher in 2000. A comparison of average prices illustrates the price difference.[19]

A comparison of hourly loads reveals more.[20] On both days, substantial load was supplied through the ISO-controlled real-time markets, 146,000 MWH in 1999 versus 191,000 in 2000. However, during the peak hours between 12 and 6 p.m., 3000 fewer megawatts were supplied through the day ahead market in 2000 than in 1999. This suggests sellers may have been withholding power from this market in order to drive up prices in other parallel markets. The ISO has adopted a policy of making premium payments for "replacement reserve" which can be called upon when supplies are short. On June 29, 2000, nearly 10 percent of load was supplied through real time markets at "replacement reserve" prices that were 50 percent higher than the astronomical prices above. The ISO has refused to provide us with the data necessary to determine what really happened.

On both days, prices in real time markets reached the current price cap -- $250 per megawatt in 1999 and $750 in 2000. Had the 1999 price cap of $250 been in effect in 2000, Californians might well have saved at least $110 million on that day alone. On August 1st, after Governor Davis requested action, the ISO voted to reinstate the 1999 $250 price cap, effective August 7th. This reduction to last year's levels will have some moderating effect on retail prices in the coming months. However, if the ISO continues to purchase substantial replacement reserves at uncapped prices, purchasers of California power will still be forced to pay higher prices.

Total energy usage on June 29, 1999 was 763,000 megawatt hours, at a cost of approximately $45 million dollars. On June 29, 2000, Californians used 795,000 megawatt hours, that cost them over $340 million.

Warm weather alone does not explain the magnitude of the enormous run-up in wholesale prices. Wholesale electricity costs were seven times the previous year's on days when loads were comparable. Further, as the chart below shows, the highest loads for 2000 were consistently well below l999 peak loads.

| Weekly ISO Peaks, May-June 2000<br>With 1999 Peak and Forecasted Peak for 2000 | | | |
|---|---|---|---|
| Week Ending | Peak Day | Low for the week (MW) | High for the week (MW) |
| May 6, 2000 | May 2, 2000 | 18,983 | 33,148 |
| May 13, 2000 | May 12, 2000 | 18,762 | 31,287 |
| May 20, 2000 | May 19, 2000 | 18,140 | 34,375 |
| May 27, 2000 | May 22, 2000 | 20,041 | 39,521 |
| June 2, 2000 | June 1, 2000 | 19,910 | 36,137 |
| June 9, 2000 | June 6, 2000 | 19,502 | 35,417 |
| June 16, 2000 | June 14, 2000 | 19,065 | 43,447 |
| June 23, 2000 | June 21, 2000 | 20,482 | 41,414 |
| June 30, 2000 | June 27, 2000 | 18,302 | 42,693 |
| | | | |
| July 17, 1999 | July 12, 1999 | 20,710 | 45,574 |
| | | | |
| Source: California Independent System Operator, Load comparison summaries, July 1999, May and June 2000, Press release dated May 10, 2000. | | | |

California normally experiences similar weather conditions for extended periods in later summer months. Yet never before during a heat wave have purchasers paid the prices for California power that they have paid this summer.

Moreover, higher wholesale prices this spring cannot be explained by higher wholesale prices for natural gas, which fuels most California power plants. Indeed, gas prices have almost doubled over the past year. However, wholesale prices for power in June 2000 have increased as much as tenfold over last year even during periods when demand was no higher than during comparable periods in June 1999. Even off-peak prices in June 2000 are more than four times their level in June l999. Even if natural gas comprised 100% of power plant operating costs, the increase in natural gas prices would not explain the higher wholesale prices in California in June 2000.

The unprecedented price levels of June 2000 may have had one predictable result. Many energy companies, including some participants in the California market, made very high profits during the second quarter. Detailed financial information recently reported by power plant owners is contained in Appendix A. Although it is difficult to isolate the financial results from California operations, power plant operators are reporting extraordinary profits for the summer. One company that purchased 1354 MW of power generating capacity from the utilities reported a 176% profit increase for the quarter ending June 30.

Although these businesses also produce other products than electricity and sell them in other markets than California, such high profits suggest that this group of companies benefited substantially from the summer's unprecedented wholesale electricity price run-up in California. As a PG&E Vice President recently explained “If you’ve got the only Beanie Babies in town, you can charge whatever you want….Is that (price) gouging? I don’t know.”[21]

The Federal Power Act requires that electric rates be “just and reasonable.” Traditionally this has meant “cost based” rates in which investments in new or refurbished power plants were amortized over a long period of time, and profits were set at a reasonable level. Under the new market structure, wholesale prices for electricity are not necessarily based on costs. The FERC now permits power plant owners to sell wholesale power at “market-based rates,” with very little evidence to support those rates as just and reasonable. It appears that the FERC’s assumption—that the market will discipline wholesale prices—is not a reasonable one at this time in California.

While the profits of unregulated California power plant owners rise, the summer’s wholesale price spikes are putting PG&E and Edison at risk. California’s utilities must buy high priced electricity in California wholesale markets, but under the mandated rate freeze, they cannot raise the retail rates they charge customers. Because they are still subject to the rate freeze imposed by AB 1890, PG&E and Edison must bear the power costs that exceed their revenues.

PG&E and Edison incur these costs when they buy power from the PX on behalf of their customers. Under the terms of AB 1890, PG&E and Edison could potentially be liable for billions of dollars in excess generation costs. The extent to which Edison or PG&E will ultimately have to bear those costs will depend on the future prices of wholesale power, and net costs when balanced against the wholesale profits received as a power producer (for power from, for example, their nuclear generating units, Diablo Canyon and SONGS).

FERC-authorized price caps imposed by the ISO have limited wholesale prices so far. On August 1, 2000, the ISO reduced the price cap from $500 to $250 per megawatt. However, the ISO’s authority to impose price caps expires on October 31, 2000, absent a FERC extension. Without wholesale price caps, future wholesale electricity prices will almost surely continue to increase in the next several years.

## ***4. Did Electricity Sellers or Electricity Buyers Game the System?***

Properly functioning electricity markets involve producers and consumers voluntarily selling and buying at mutually acceptable prices. Electricity is essential to the public welfare. Protecting the public interest requires that electricity be delivered at an acceptable price, electricity cannot be given up if the price becomes too high. Because the purchase is not discretionary, market theories of willing sellers and buyers with alternatives do not apply.

The California "electricity market" actually consists of a number of segmented and overlapping markets. In some of the markets traditional supply and demand dynamics may apply. However, in the last and ultimate market – the real time market conducted by the ISO, buyers have no alternatives. All demand must be met.

The ISO is obliged to ensure that all demand is met, and also to provide for adequate reserve support, including "replacement reserves". There is no other option in the real-time market. Even the other markets, - the California Power Exchange, the Automated Power Exchange, and the bilateral markets, - are affected by the ISO's activities. When supply becomes tight in relation to anticipated demand, prices in all markets increase, in part because of the knowledge that unfilled demand in the final real-time market must be met - even if it is met at a very high price. This knowledge may induce sellers to withhold supply in order to raise prices in all markets. Withholding can be accomplished in very sophisticated ways.

The combination of a flawed market structure and lack of investment in new generation over an extended period of time now exposes Californians to shortages and high prices. The ISO is a captive—as the buyer of last resort, it cannot refuse to buy at premium prices. Even worse, the ISO cannot reduce its price exposure through financial instruments or long term contracts. In addition, the largest consumers - the utility distribution companies – have only limited authority to reduce their own exposure.

Where generation sellers also control transmission, they may have an unfair advantage, viewed from the perspective of competitors. Adopting the competitors' perspective, FERC has required "unbundling" of the transmission grid, so that combined control of generation and transmission cannot be the basis for undue discrimination in favor of the transmission owner's generation, even if that generation is dedicated to serving the generator's own retail customers.[22]

On a number of days in June 2000, electricity demand was high. Being well-informed about market conditions, power-plant owners were able to bid high selling prices with the near certainty of selling power on those days. The owners' bids did not correspond to their variable costs, but were based on the high and inelastic levels of demand. This pattern was particularly apparent during the week of June 26 through 30. Ironically, this was the time when the ISO board, where power plant owners are well represented, was considering reducing wholesale price caps in order to limit power prices. The ISO decided not to lower price caps.

We have posed the question whether suppliers could have colluded to drive prices higher. Such behavior would not be necessary to drive prices up, but it is certainly worth investigating to determine if it did occur and did contribute to the billions of dollars taken out of California during June. Pricing patterns in the PX "day ahead" and "day of" markets raise questions about the bidding behavior of market participants that cannot be coincidental. The EOB and the CPUC have been unable to obtain information about generator and marketer bidding behavior, partly because the ISO and PX have refused to provide that information to state agencies.[23] Because we have not had adequate information, we have not determined whether anti-competitive or illegal conduct occurred during June. The Attorney General, U.S. Department of Justice and FERC should cooperate with us in pursuing this question diligently.

Nevertheless, a comparison of prices and demand levels in 1999 and 2000 is instructive. Wholesale market sales were virtually unchanged for comparable periods in 1999 and 2000. Yet retail prices increased by up to ten times from 1999 to comparable days in 2000. This cannot be explained by comparable increases in costs or supply-and-demand balances. Some commentators and interested parties characterize the effect as "scarcity rents," suggesting the exercise of undue market influences, or even collusion.

It is unclear whether collusion or gaming caused the Bay Area black-out. However, it is clear that the unavailability of generation contributed to the Bay Area grid instability on June 14. Better coordination of generator maintenance schedules might well have helped maintain reserve and operating margins. But the issue of coordinating maintenance schedules can cut both ways. The failure to coordinate could result in the inadvertent scheduling of maintenance of several power plants simultaneously, and the consequent unavailability of needed generation. On the other hand, power-plant owners' coordinating maintenance schedules could result in a sophisticated form of market allocation, and a potential violation of the anti-trust laws. State authority to coordinate maintenance may be the only way to resolve the dilemma.

This report cannot provide an exhaustive analysis of the possible problems in the way electricity is bought and sold in California. We do, though, have enough information to suggest that the system is operating in ways that are contrary to the public interest.

### ***5. On June 14, 2000 Several Bay Area Power Plants Were Out of Service***

The lights went out in the Bay Area in part because nine power plants were out of service, either for scheduled maintenance or repairs, or were operating at limited capacity. PG&E could not import enough power to make up for the lost generation because the region has limited transmission facilities over which to import power. The following chart shows the status of power plants in the Bay Area that were not available on June 14.[24]

If any of these plants had been up and operating, the June 14th black-outs might have been averted.

This summer so far, the power supply system has also been supplemented by curtailments to "interruptible" customers, generally large industrial customers that in the aggregate consume more than 3,000 MW of load. Interruptible customers contract for discounted electricity rates year-round in exchange for agreeing to be interrupted when power reserves dropped below 5%. This program helps to manage electricity supply in times of shortage, but the amount of capacity available is limited because relatively few customers are willing to shut down their industrial processes whenever the electric system is stressed.

So far this year, the ISO has interrupted power to these customers when it has called a Stage Two emergency. The interruptions are voluntary, and utility ratepayers spend over $200 million per year to obtain the right to interrupt certain customers in times of short supply. The lower rates interruptible customers pay year round average out to $60,000 to $70,000[25] per megawatt per year in benefits for interruptible customers. Large California customers who account for more than 3,000 MW of load are currently enrolled in the PUC's interruptible programs. Limits on the number of total hours of interruption prevent interruptible customers from being shut down for unreasonably long periods, or unreasonably often during the year. For example, PG&E limits interruptions to no more than 30 per year for any given interruptible customer, and Southern California Edison limits its program to 25 interruptions per year. The discount is a cost assumed by California customers for this additional electricity resource.

### ***6. Could the ISO Have Averted Power Outages on June 14?***

The question remains whether the ISO might have averted power outages in the Bay Area. The City of Santa Clara, which operates its own utility, took an innovative approach to the supply squeeze on June 14. It contacted large customers and asked them to voluntarily cut back their power so that they would not lose all power. As a result, the City acquired voluntary load reductions of 7%[26]--manageable brownouts instead of blackouts. By taking similar steps, the ISO might have reduced demand enough to avoid forced blackouts.

In addition, the ISO made its blackout decisions based on a software program that has never been subject to public scrutiny or approval. The program's decisionmaking criteria and assumptions concerning the point at which blackouts must be ordered have never been validated in a public process or by a public agency. Moreover, the ISO's computer model required demand reduction received no public scrutiny before its use on June 14.

Additional power may be available from QFs that have power production contracts with utilities, which in turn sell the power into the grid. These contracts may not currently provide enough financial incentive for QFs to produce power above minimum contract requirements. The utilities may be able to motivate QFs to produce more power by committing in advance to a level of payments for additional power when needed to forestall supply shortages and modulate prices. Some market participants have estimated informally that such action could free up an additional 500-1000 MW of power around the state.

## ***Conclusions***

California customers have so far this summer endured electricity outages and, in San Diego, huge increases in their bills as a result of price spikes in wholesale markets. The extent of the summer's wholesale price spikes cannot be explained by hot weather, increased natural gas prices, or increases in demand. Other problems – such as out-of-service power plants, transmission supply constraints and a dysfunctional power market – may have contributed to the problems so far this summer.

The state's short-term problems appear to evolve at least in part from past public policy choices regarding electricity supply combined with customer demand that has grown as a result of the state's robust economy.

# III. WHY CALIFORNIA'S ELECTRIC SYSTEM IS IN TROUBLE

The high prices and outages of June 2000 were caused by a number of events and circumstances:

? New power supplies are inadequate to meet increasing demand

? Existing power plants are aging and in need of attention

? Limited transmission facilities have also contributed to short supply, especially in San Diego and San Francisco.

? The State has reduced the role of energy efficiency and construction of renewable energy resources in recent years.

? California's economy has flourished, creating new demand and its high technology sector is highly dependent on electricity.

? California's electric system is no longer consistently reliable.

The curtailments of power to large customers on June 14 were not isolated. The ISO has called 10 Stage II alerts in the past three years.[27] Half occurred this year, with more alerts certain as the summer progresses. The ISO has curtailed power to more than 1200 of industrial customers since 1998, some customers for more than 20 hours this year alone. Before 1998, neither SDG&E nor Southern California Edison had ever interrupted industrial customers. Although PG&E had interrupted industrial customers prior to restructuring, the frequency of curtailments to its industrial customers has significantly increased this year. The increase in Stage Two interruptions show that the electric system's margins are much narrower today than historically.

***1. California Has Made Only Limited Investments in New Power Plants in the Past Twenty Years***

New power plants are capital-intensive and have long lead times between planning and completion. Between l996 and 1999, 672 MW of net generation capacity was added to California's electric generation capacity, adding less than a 2% capacity improvement to the approximately 55,500 MW on line.

| Comparison of Net Generation Capacity Additions and Load Growth, 1996 through 1999 | | |
|---|---|---|
| Year | Net capacity Additions (MW) | Growth of Peak (MW) |
| | | |
| 1996 | 462 | 2,376 |
| 1997 | 153 | 2,005 |
| 1998 | 6 | 2,464 |
| 1999 | 51 | (1,323) |
| Increase | 672 | 5,522 |
| Source: California Energy Commission | | |

State and federal regulatory policies have, discouraged new construction generally, and new investments by utilities in order to encourage others to build generation and increase competition in generation markets. However, potential investors in new generation faced uncertainty because of a number of policies and determinations:

? PUC regulatory ratemaking policy has provided incentives for utilities to forego new investments and defer maintenance. Specifically, "performance-based ratemaking" gives utility managers an incentive to save short term costs to make short term profits and to forego long term investments.

? State regulators in the 1990s abandoned Integrated Resource Planning – in favor of letting the market decide where and when to build new power plants and where and when to take energy efficiency measures. As a result, investors assumed most of the risk of a plant's success or failure. Coordination to ensure adequate electricity supplies was subject to these market changes.

? The PUC's "Biennial Resource Plan Update" (BRPU) policy pursued construction of new generation plants by unregulated firms or utility affiliates. The BRPU required utilities to put their planned new generation out to bid. Prospective generators submitted bids and began to plan construction, but the PUC ultimately never approved new plant construction in the BRPU proceeding.

- On February 23, 1995 the PUC's BRPU process was suspended when FERC ruled that California could not require its utilities to enter into long term contracts with the renewable power producers. FERC relied on a technical legal principle that prevented California from requiring utilities to sign contracts that resulted in rates being set above avoided cost.[28]

- State and federal tax credits for construction of renewable resources expired in the l990s.

- State siting procedures in California are complex and create investor risk because of California's commitment to environmental protection and public participation in the permitting process.

- California's weak economy in the early l990s may have discouraged new investments in the State's infrastructure.

- The changing regulatory environment through the 1990s caused risk-bearing investors to wait until clear rules were established before applying to build new power plants.

## ***2. California's Demand for More Electricity Has Outstripped New Supplies***

Between l996 and l999, California's growing economy caused peak period demand to increase by over 5,500 MW. The State's population, already the largest in the country, is increasing by 600,000 people annually. However, new demand for power increased even faster than the rate of growth in the State's economy.

As the chart below shows, California's demand is expected to grow faster than new power plants will be built for the next several years.

California—especially Silicon Valley—is the leader of the digital economy. California ranks first in the nation in the number of high-tech jobs.[29] This new technology economy needs higher quality and more reliable power. Although the new economy's contribution to increased demand has been debated, clearly a shift in industry sectors contribute to our society's increasing use of all forms of technology that runs on electricity, contributes to electricity demand. According to the Electric Power Research Institute, computers consume about 13% of the nation's power. Another study places the electricity load attributable to the new economy at 2%.

Whatever the level of electricity required, the effects of the digital economy on energy requirements will be felt even more strongly over the next few years, as more individuals and businesses take their commercial transactions on-line. Over the last three years the amount of information available on the Internet has increased ten-fold to over one billion discrete pages. Internet use by individuals in 1999 was 80% higher than the previous year. This market has a tremendous potential for growth—68% of manufacturers report they do not yet conduct purchasing transactions on the internet. California simply must keep up with the energy needs of high technology, a highly productive, fast growing segment of California's economy.

Technology firms and, increasingly all businesses, require high quality, 24 hour power to operate successfully. In the digital economy, power interruptions are extremely costly. Hewlett Packard reports that a 20-minute outage at a circuit fabrication plant would result in the loss of a day's production at a cost of $30 million. For purely digital companies, such as Oracle, the price of a power interruption is "millions of dollars per hour," according to the company's energy director.

Smaller customers' electricity demand is also critical. Customer demand for electricity appears to be "inelastic" during certain times of the day and in hot weather[30] When demand is inelastic, the need to run air conditioning or maintain a threshold level of electricity use contributes to the risk of price increases during periods of high demand, such as hot weather.

### ***3. California Power Plants are Aging and May Need More Maintenence***

California's power plants are aging. The chart below shows that 55% of the State's generation facilities are more than 30 years old. Older plants need to be taken out of service for maintenance and repairs more often than more modern plants. Deregulation of generation may have also motivated owners to run California plants longer and harder, leading to subsequent reductions in reliability.

A recent PUC investigation suggests that maintenance problems at some Bay Area power plants are chronic, and have already resulted in both "forced outages" (those that occur because of a system problem and cannot be avoided) and long scheduled downtimes. During June 2000, two of the five power plants surveyed had forced outages and one was down for scheduled maintenance.[31] Moreover, old plants emit more pollutants than newer more efficient plants in general. Older plants may well need to schedule additional downtime for environmental retrofits or rehabilitation, especially to keep in compliance with emissions permits.

The PUC's investigation analyzed the status of the power plants during June 2000, reviewed the plants' work management systems and maintenance programs, and examined maintenance records, operations logs, plant evaluation and assessment reports, failure analysis reports, and operations and maintenance manuals.

The review revealed several causes for concern.

? Generation owners decide when to schedule maintenance downtimes; the downtimes need not be scheduled when they would be least disruptive to the system. Maintenance was scheduled for June that could have been done before summer, or at least could have been coordinated with other plants' maintenance to keep a comfortable reserve available.

? Some maintenance took much longer than expected, increasing the risk of generation shortage.

? Bay Area power plants are aging, so maintenance problems will worsen in the coming years. Moreover, when a plant is brought down for one repair, other problems are discovered. This extends plant downtime. And finding spare parts for unexpected repairs on an old plant can be time-consuming and difficult in itself.

Over the next few years, many Bay Area power plants will be out of service for months to address maintenance problems that arise because of plant age.
The time lost to a forced outage is unpredictable. Component failure can cause an outage lasting less than a day to as long as six months or more, which occurred to a power plant unit in 1999.[32] Scheduled outages for equipment overhaul may take a week or up to four months or more depending on the extent of the overhaul.

### ***4. California Retreated from its Previous Commitments to Energy Efficiency and Renewable Power.***

Historically, California addressed issues of energy supply and energy demand through an integrated assessment of energy demand and energy resources. The Warren-Alquist Act of 1974 requires the California Energy Commission to prepare a Biennial Report that analyzes an integrated supply and demand and provides the basis for a State energy policy. State energy policy included two elements: a commitment to analysis and management of electricity demand; and a commitment to resource diversity, recognizing that reliance on a single fuel source makes the system vulnerable. During the 1980's, California utilities boasted about having the most diverse mix of energy generation technologies in the world.

During the same period, the PUC developed utility-managed energy efficiency programs, funded through utility rates, which reduced demand and energy usage. The PUC also aggressively implemented federal policy enacted in 1978 under the Public Utility Regulatory Policy Act (PURPA).[33] PURPA complemented the State's fuel and resource diversity policy by requiring utilities to contract with "qualifying facilities"-- energy producers that used renewable resources, such as wind, solar, biomass, and small hydroelectric generation, or use newer, more-efficient fossil-fuel technologies.

In the 1990s, the PUC's policy shifted away from the emphasis on renewable power production and strategic energy efficiency. The PUC shifted to funding energy efficiency programs that encouraged competition between energy service providers and away from than the specific, high impact, energy reduction programs that had previously been so successful. The effectiveness of these market-based programs has not yet been established. For example, existing building standards fall far short of their maximum energy efficiency potential. The PUC also suspended its program of promoting renewable resources in the Biennial Resource Plan Update (BRPU) proceeding after the FERC found technical problems with the way that the PUC set the price utilities would pay for power. The PUC subsequently moved away from its commitment to renewable energy in favor of the electric restructuring process that it initiated in 1994 and that lead to AB 1890. Other agencies followed suit.

In addition, current energy efficiency policy centers on an academic debate about whether customers will be more responsive to prices with "real time" or "interval" metering. Theoretically, such meters will educate consumers as to the changes in electricity price as customers use that electricity. Economists predict exposure to high electricity prices will cause consumers to manage consumption, for example, by shifting electricity use to lower cost times of day or reducing usage in warm seasons.

However the practical aspects of this concept are complex. The full cost of installing and operating meters especially for residential and small commercial customers has yet to be calculated with any precision. Edison currently offers installation of hourly meters that cost about $400 for a small customer plus installation costs of as high as $228. This meter does not even provide price information customers can see in real time. It stores information for retrieval (and billing) at a later time. In order “real time” metering to work, the customer must also know the price of electricity. Most meters on the market today require the customer to access prices by way of a separate contemporaneous source, such as the PX Internet site. Investigating the costs and technology advances that may help drive down those costs is worth exploring, but the state and costs of metering technology today indicate that customers cannot easily adjust energy use with metering alone.

Moreover, metering every residential and business customer will not necessarily change the buying patterns of or provide any benefit to customers who do not use power during peak periods (for example, those who are at work and school during the day) or who cannot change buying patterns for reasons of health, comfort, or business necessity. (Examples include seniors, customers who live in the desert). For those customers who must use power during high priced periods, switching to real-time pricing with residential meters installed to identify high priced periods will result in higher bills, rather than bills calculated using the average prices they pay now. Customers who cannot afford higher bills, such as seniors on fixed incomes, may compromise their health and safety trying to avoid them. Metering offers the promise of significant control over non-essential electricity use. However, technology questions, costs and obsolescence concerns in this fast changing field caution against statewide immediate metering programs as the primary tool for customers to bring down retail prices. And energy efficiency efforts may well be hampered by focussing on undeveloped technology that has such complex policy implications.

In the AB 1890 negotiations, proponents of renewable energy supplies and energy efficiency won legislated funding for energy efficiency renewable resources. However, pursuing a competitive market structure, policy makers made funding for these programs a low priority. The current funding for these programs is almost 70% less than it was in the early 1980s. The State’s retreat from funding energy efficiency and renewable energy programs occurred despite the demonstrated economic benefits that energy efficiency brings to the California economy. RAND, for example, estimates that energy efficiency in the past 20 years has provided $1000 in economic benefits to each Californian.[34] These benefits complement the State’s commitment to environmental quality.

### ***5. California’s Commitment to Environmental Quality Guides the State’s Supply Options.***

The California Environmental Quality Act (CEQA)[35] and the federal Clean Air Act[36] are two of the principal laws that ensure preservation of public health and environmental quality when power plants are constructed and operated. These laws focus on the environmental impacts of California's power choices.

CEQA requires evaluation and mitigation of potential environmental impacts from a power plant before the State allows construction. In addition to reducing negative environmental effects caused by any one plant, CEQA could be used to plan strategically for power plant siting, encourage and streamline construction in key locations (e.g., to bolster grid reliability) and ensure lower cancer risk and ozone damage from emissions.

Failure to conduct adequate environmental review can result in CEQA litigation by citizens or local government agencies that can delay, change or eliminate a power plant project.[37] Although CEQA exempts emergency measures, the statutory exemption is exceedingly narrow and only applies to measures taken in response to unexpected catastrophes that threaten the public. Courts have prevented agencies from using the emergency exemption when those agencies faced ongoing or existing conditions.[38] An attempt to use this exemption to address short-term reliability risks court action, and it reduces long-term planning for efficient, renewable power sources.

In addition to CEQA, federal, state and local laws govern air emissions from power plants. Local Air Districts enforce state, federal, and local air quality laws for stationary sources.[39] Permits for major pollution sources, such as power plants, involve federal- and state- enforced rules, while small power units are regulated by local Air District rules that restrict size and limit operational schedules. As a whole, these rules limit power plants' discharge of cancer-causing or ozone-depleting emissions and chemicals, and they attempt to increase the efficiency of electricity generation.

Both federal and Air District rules control emissions by requiring new air emissions sources, including power plants, to have pollution control devices that meet "Best Available Control Technology" standards and obtain pollution "offsets" before beginning operation. In addition, existing power plants must reduce pollution emissions according to pre-set schedules by retrofitting old plants, adding new controls and/or reducing total emissions in the area by getting "credit" for reductions from other sources.

The environmental and health benefits obtained by retrofitting and/or replacing old plants with new ones are large and measurable. For example, two existing San Diego power plants South Bay and Encina, emit 1100 tons of NOx per year <u>each</u>,[40] while the new Otay Mesa plant will emit 90% less NOx per year (100 tons) while producing the same amount of energy as either of those plants. One of the promises of deregulation was that by building new, clean plants, California could take old, polluting plants off-line and thereby improve California's air quality. The failure to build new, clean and efficient capacity as demand increases means that California is facing even worse air quality because of the need to keep the old plants. This is exacerbated by, the environmental pressure of additional emergency emissions.

Although the Air Resources Board (ARB) has created new rules to simplify calculations for air offsets and credits, providing a priority to power plants to obtain available offsets would require a change in state law. At present, owners of offsets can sell those offsets to anyone, without regard to the need for future power plants. In San Diego, the owners of South Bay and Encina power plants control most of the area's air pollution offsets. They have no incentive to sell them to clean new power plant competitors.

Health concerns about power plant emissions are real. Preliminary ARB analysis shows that if all of the diesel emergency generators (approximately 1000) in San Diego fired up for a single day, it would add 75 tons of NOx to San Diego's air and increase public exposure to cancer-causing toxics. These emergency generator units have no emission controls at all. The Bay Area has two to three times as many diesel generators as San Diego. Increased use of currently installed emergency generator could threaten the federal Clean Air Act attainment status for the Bay Area. The ARB estimates that one diesel unit operating for 200 hours will cause 100 new cancers per million people.

Owners of older power plants are put in a tight squeeze between the ISO rules pushing for additional run times and capacity and environmental requirements establishing minimum maintenance and retrofit schedules. If these plants stay up and running for the good of the system as a whole, they risk violating negotiated or required retrofit schedules. The failure to meet or exceed such schedules reduces the general availability of emissions credits for those or additional power plants, creating a spending problem. For example, the time it takes to retrofit old plants can be as short as a month or as long as three years. Costs vary widely depending on the size of the unit and the type of pollution controls installed. Most of that retrofitting time is spent preparing to install the controls; retrofits ordinarily cause plants to be non-operational for only a few days to a few weeks at a time. Some of the retrofitting rules were designed to use market incentives to encourage faster retrofits, enabling those who moved ahead of schedule to sell "credits" to those who were unable to do so. California's power crunch threatens to delay old power plant environmental retrofits because we need full-time power production from those plants. At the same time, delays would squeeze the number of credits available for purchase by plants or other industrial plants that cannot meet previously established schedules.

One short-term suggestion for relieving immediate power needs is to use emergency generators more frequently or in advance of a Stage 3 emergencies. But this option creates significant environmental and public health damage. Emergency generators are old, typically burn diesel fuel and have few if any pollution controls. Air district permits constrain operation to emergency situations, test intervals, and/or total yearly operating times; more frequent operation subjects the owners to penalties. Emergency generators have reported that the ISO ordered them to operate their generators in advance of declared emergencies and owners of those units have received violation notices from local air districts for violating their permits.

Using emergency generators caused both a short term and a long term problem. First, they create significant air quality and health problems when they run. These problems are exacerbated because hot days where electricity is in short supply are often also very smoggy days. Second, although investment in pollution controls can reduce some of the pollution, allowing these generator to run on a periodic or semi-regular basis, might cause the ISO to absorb and come to rely upon these power sources more regularly. Instead of investing in cleaner more efficient fuels, dirty old technology would become part of the power baseline, and it could displace investment in cleaner, more efficient means.

## ***6. California's Wholesale Electric Market is Flawed***

California power markets are not now competitive. The ISO conceded this in its Market Surveillance Committee's most recent report: "California's energy and ancillary services markets have not been workably competitive during the last two summers…(W)e are unable to conclude that California's energy and ancillary services markets will be workably competitive during high-demand periods this summer."[41]

The reasons for the lack of competition may be many. The complexity and fragmentation of power purchase markets may be partly to blame. Their structure may encourage market participants to game the system to their benefit even while obeying the rules.

Wholesale electric power has been fragmented into many products, that are independently priced in a series of auctions administered by the PX and ISO. The decision to segment wholesale power into four or more separate products creates significant market inefficiencies that serve to provide gaming opportunities for market participants, opportunities that may be perfectly available under current rules.

Under the existing design of the system, the ISO cannot consistently purchase power at the lowest price. In theory, electricity buyers will find the least cost products; however, they may not have an incentive to do so. This constraint on the ISO provides another gaming opportunity for power plant operators. Further, the ISO is not permitted to purchase electricity from the PX when PX products are less expensive than the products bought and sold in ISO auctions.

Creating further possible problems is the use of “scheduling coordinators” . Scheduling coordinators are the intermediaries between buyers and sellers and the ISO. Scheduling coordinators coordinate the pricing activities of generators, other marketers and large consumers to balance supply with demand.

This process may promote collusive activity because Scheduling coordinator transactions are not necessarily at arms’ length. Scheduling coordinator functions exhibit significant economies of scale and scope, key attributes of a potential monopolist. As a result, Scheduling coordinators could evolve into large, unregulated oligopolies that have the opportunity to set the price of power and power products.

### Conclusions

California’s electricity supplies have not kept pace with the state’s economic growth. Lagging investments in power plants result partly from regulatory uncertainty and a reliance on competitive markets to assume a comprehensive planning function that the state had previously performed on behalf of consumers and the state’s economy. As power plants aged, California’s economy grew and policy-makers retreated from aggressive efforts to promote energy efficiency and investments in renewable power resources. Moreover, the market itself is flawed. This compounds the mismatch between supply and demand for an essential service.

These circumstances show that electric system governance is just not working for the benefit of California customers at this time.

## V. GOVERNANCE OF THE NEW ELECTRIC STRUCTURE CANNOT ASSURE CALIFORNIA GETS REASONABLY PRICED, RELIABLE ELECTRICITY FOR CALIFORNIA

Through the Twentieth Century, inexpensive, reliable electricity was assured by the close supervision of public agencies responding to public concerns and answering to the people of California. California's current electricity industry structure places autonomous, self-governing entities in roles formerly performed by government or utilities – planning, building, maintaining, and operating generation and transmission, and setting prices. This decoupling of accountability from control, and the dispersion of responsibility to market participants and away from government and utilities means that the events of Summer 2000 could be a permanent feature of the California economy.

Currently, the ISO and the PX have the greatest influence over the pricing and day-to-day operations of the State's electric system. Yet despite of their enormous authority, the law does not require either the ISO or the PX to act on behalf of the state's electric consumers or its economy. AB 1890 provides that the PX and the ISO are accountable to their boards, which are comprised of "stakeholders," shown in the table below. Although some board members may have ties to consumer groups, they are in the minority. On the PX Board, only two of 25 current members represent residential consumer interests. On the ISO Board, only two of 27 current members represent residential consumer interests. Many board members are sell power or own generation facilities and therefore have an interest in keeping prices high. None of them has a duty to serve the California public interest. The ISO board is also self-perpetuating: it appoints its own members, subject only to approval by the EOB and the FERC. The ISO is also pursuing a change in its status to become a regional transmission operator (RTO).

In addition, as private entities, the ISO and PX are not fully subject to State laws regarding the conduct of their business. These boards conduct some of their business privately--in executive session—and then assert that they are not required to report the results of these deliberations.

Although the federal government oversees the ISO and the PX, federal regulators pursue national interests, not necessarily those of Californians. For example, the FERC does not incorporate California's strong environmental values into its decision-making.

FERC's oversight of the ISO and PX is limited in practice partly because it does not follow a comprehensive model or set of policies. Instead, FERC generally regulates the ISO and PX by approving or denying tariff proposals. California is one system among 50 different systems. Therefore, as a practical matter, the FERC probably cannot provide close supervision of the complex industry structures and the hundreds of utilities in 50 states, half of whom have created new structures that rely increasingly on federal action.

Finally, FERC does not have comprehensive oversight of California's interrelated electric system. Accordingly, it cannot weigh the public policy options that might be available to affect development of each component part of the system–transmission, generation, distribution—and the costs and advantages of choosing among such alternatives as new construction, new rules, new programs or technical innovations. FERC cannot, for example, choose between the construction of an emergency peaking plant versus a substation upgrade according to the relative costs and benefits of each, when markets fail to respond to a need. It cannot address a regional transmission problem by funding investments in energy efficiency resources even if transmission facilities are more expensive. While no single agency, state or federal, may be in a position to regulate all parts of the electric system equally and comprehensively, the current structure is too fractured to assure California interests are promoted and protected.

The State needs to reconsider oversight in the following areas:

? **Planning for New Generation.** The ISO has assumed increasing responsibility for planning how match supply and demand and transmission system upgrades in coming years. But the ISO does not set generation prices and is not accountable to the public for keeping prices reasonable. Energy efficiency, renewable energy sources, and local concerns like power quality in Silicon Valley need play little or no part in the ISO's decision-making.

? **Reliable Operations.** The ISO, which owns no electricity facilities itself, today runs the transmission system, negotiates with generators to provide reliability services, and performs virtually all of the non-distribution functions once performed by utilities. However, the ISO sends no monthly bills to residential customers, has no phone-bank waiting to receive complaints when the lights go out, and is accountable only to its board – dominated by market players, not by representatives of the public interest. The ISO may also find it difficult to coordinate fully with municipal utilities, some of which own generation and transmission, because the municipal utilities fear being incorporated into a non-governmental system they don't control.

? **Power Plant Maintenance.** Just as the ISO is not directly accountable to the public, the current structure in California breaks the link between power plant owners and ultimate consumers. For example, neither the ISO nor any State agency has the authority to direct a generator to continue producing power in an emergency. For a century, when emergency threatened the reliability of California's electricity supply, state regulators and utilities had the responsibility and the authority to take immediate, appropriate action, and were directly accountable to the people. Today, with aging power plants, California has a structure that puts maintenance decisions entirely in the hands of power plant owners, whose interests conflict with those of consumers.

? **Pricing.** In California today, the price of wholesale electricity is set by a spot market, not by government or utilities. The price of electricity is also not necessarily based on power plant costs or even what consumers are willing to pay. In the PX market, all electricity trades for a single price, a price set by the highest winning bid, even though other power plant owners are willing to sell their power at lower prices. This guarantees that customers do not receive the benefits of competition. This result is built into the California system as an integral part of the market design. Also, because California has two markets for power – one operated by the PX in a "day ahead" market and one operated by the ISO in a "real time" market – generators may withhold power in the PX day ahead market in hopes of realizing higher prices in the real-time market. During some periods, it is in the generator's interest to withhold some power because in so doing it can drive prices up, according to Severin Borenstein, a professor of business at UC Berkeley and PX Board member. According to Borenstein, restructured electricity markets may have attributes where "if firms of noticeable size are not exercising market power, they are doing so out of the goodness of their heart, and against the interest of their shareholders."[42] The "ancillary services" market – the market for things like reserve supplies – may also be susceptible to gaming.

? **Regional Future.** The current structure of California's electricity industry creates risk that the high prices and poor reliability of this summer will continue for months, perhaps years to come. And despite the inherent problems and the impacts on California consumers, ISO seeks to expand its control to include not just California, but neighboring States as well. This would widen even further the gap between accountability and control. It would also dilute the ISO's concern for the State that created it.

## Conclusions

The operation of California's vast and valuable electric system is now controlled primarily by the ISO and the PX, organizations that have no duty to serve California's consumers or economy. The ISO and the PX report to boards that are comprised of "stakeholders," none of whom represent the public and many of whom have an interest in keeping wholesale electric prices high. These organizations do not have contact with the ultimate consumers of power and conduct much of their business in private.

The pricing system, in combination with inelastic customer demand and the ability of power sellers to withhold supply, results in wholesale prices that may bear no relationship to power producers' costs. At the same time, no government body is compelling power plant construction or maintenance during this period of aging plants and short supplies.

In sum, power supply shortages, increased demand and a dysfunctional market are converging to undermine the state's ability to assure its businesses and citizens have clean, reliable and reasonably price electricity. California deserves better.

# V. RECOMMENDATIONS

Solving California's myriad, intertwined energy issues is certain to be expensive, time-consuming and complex. Despite our best effort, we cannot find solutions that will work unless we have reliable evidence and accurate comparisons of costs. We must bear in mind that in the capital-intensive, long lead-time energy industry, our current crisis cannot be resolved overnight or merely by passing new statutes. Instead, numerous individual pieces of the energy puzzle must be fitted together to form the map of California's path electricity sufficiency and reasonable electricity prices.

This summer's blackouts and price spikes were not isolated events, nor will they be rare unless action is taken. Moreover, San Diego's inadequate energy infrastructure, combined with the end of the rate freeze, leaves San Diego consumers bearing the brunt of the flaws in California's energy markets. By January 2002 at the latest, consumers throughout the State could face the same high prices San Diegans are now paying.

### *1. Work Together to Prevent Power Outages In the Next Twelve Months*

Protecting California electricity consumers – both businesses and households – lies at the heart of the emergency preparedness steps listed in Attachment 2. We cannot assume that additional power plants will be up and running this year. Thus, we must try to prevent another black-out through reducing a shifting of electricity demand during peak use hours.

Many companies have volunteered to reduce their electricity use when it is really necessary. We applaud their efforts and ask all Californians to join in conserving electricity usage for the next three months when requested. We reject the notion that companies must be paid to do the right thing - to reduce load on those days when electricity reserves become sparse. We welcome other suggestions that enhance California's ability to prevent blackouts when confronted with localized power plant outages restricting the availability of generating capacity, or with extremely hot weather.

Demand side management and load shifting actions form a crucial component of our ability to avert black-outs. For example, the State may be able to conserve 1000MW of electricity during peak demand times if the State Water project and its contractors forego water pumping during specified peak times. While this appears simple on its face, to enable water pumpers to shift the times of pumping requires equipment, coordination and an ability to hold water so that pumps can remain idle for short times. If one water user stops the pumps and the next user downstream cannot do so as well (or does not know when the upstream user stops) potential problems are obvious. Installing meters and telemetry equipment to enable water pumpers to be able to defer pumping – and to coordinate with other users and pumpers – is key to obtaining this statewide load shifting benefit.

Practical problems arise with this and every conservation or load shifting measure and will need to be addressed and resolved. Nevertheless, the potential for savings exists with some innovative thinking and coordinating efforts between the State and large consumers

Some of the simplest and most effective load shifting can be accomplished through consumer and commercial education. The Energy Commission estimates that residential air conditioning accounts for 14% of state-wide electricity demand and that dryers account for an additional increment. If California households routinely avoided running their dryers during the times of peak demand (from 2-6 p.m., generally) we could reduce not only the electricity use from dryers but also the additional air conditioning burdens created by running the dryer on a hot afternoon. We suggest investigating and implementing promising, cost effective load shifting programs as soon as possible.

### *2. Invest in Smart Energy Use To Tackle Short-Term Scarcity and Balance Supply & Demand*

Because of California's growing economy, the state can expect even tighter electricity supplies next summer and the summer of 2002. California simply must do a better job of meeting demand –through reducing both peak load and the base load of electricity required to run California's economy -- and by providing more electric power into the system. To the extent power plant construction can be avoided, problems relating to environmental consequences, and community resistance are avoided. And of course, most all power plants simply cannot be up and running by next summer. In the immediate term, the easiest solutions to the lack of supply involve decreasing base and peak demand and bringing more renewable power on line by the Summer of 2001.

We must compare each supply/efficiency option not against the cost of a black-out but against the value (costs per megawatt gained) of each available option. Policymakers should consider an aggressive program of energy efficiency programs and renewable energy development to ease the shortages projected for next summer.

Much can be done with little visible differences to businesses and consumers that make huge differences to the demand use bottom line. An extension of the public goods charge which funds and supports energy efficiency programs, is vital to continuing the State's energy efficiency and renewable energy programs.

A listing of energy efficiency programs and options is attached as Appendix 6. We suggest an immediate discussion with policymakers and experts to determine which programs are the most cost-effective. The environmental effects of each energy efficiency option should be factored into the equation when determining the value of each option. Some options can be run by utilities and energy providers; some options can be pursued on a regional or statewide basis.

The State should also advance its review of current building standards, which have not been revised for a decade. By building smart from the start, Californians can reduce the rate by which California's electricity demand increases year by year. Now is the time to improve our building standards as California's economic boom fuels new construction throughout California. Moreover, as California grows in warmer parts of the state, demand for electricity is even higher. Putting into place guidelines now that help make our buildings as efficient as possible will reduce customers bills and represent a long-term investment in California's electric supply sufficiency.

Supporting renewable energy sources is also vital for environmental protection and to assure reliable electric service next summer. The construction of new large power plants before next summer is unlikely, but California can build additional renewable energy resources to ease anticipated shortfalls next summer. Attachment 6 lists renewable options that might be available for Summer 2001, if action is prompt. Of course, solar and wind options depend upon the sun shining and the wind blowing so those energy sources are not available 100% of the time. Nonetheless, adding quick, clean, efficient electricity options to California's basket makes sense and adds to the diversity of energy sources California needs.

The options listed represent some of the creative and proven methods that we have reviewed. Although not exhaustive, they are offered to provide a foundation for further discussion.

### ***3. IMPROVING CALIFORNIA'S ELECTRICITY SUPPLIES IS ESSENTIAL***

As outlined above, both the pricing and supply problems Californians face come down to one simple fact: on some days, not enough electricity can be produced in California to meet the demand for electricity. Sufficient capacity or demand flexibility must exist for the very highest demand to be met, whenever that might occur.

Understanding the long lead times that exist for planning and construction of power plants, many energy companies and utilities are stepping up to the plate to search for additional generation sources. We suggest that all additional short-term supply options be identified and put on the table for discussion. If every option for new supply was built, connected and run, California could have additional power available, but at an unacceptable cost to rates and to the environment. As a result, the relative merits and costs of short term supply options must be discussed and analyzed by policymakers.

Several options suggested to us involve inefficient and environmentally unfriendly technologies. Other options, especially repowering and transmission improvements, seem especially promising. But every option has a financial and environmental cost to it. If capital improvements are made the costs involved in building, retrofitting, and adding new supply will be added to the rates consumers pay at the time wholesale power market problems are sending prices skyward. Because of the short supply of power, if higher polluting generation is added to the supply mix, California will come to rely on it further degrading the environment and air quality.

If projections are accurate, in five to ten years, California will have built sufficient electric supplies to power its economy. Over 4,000 megawatts of additional electricity generation is in the regulatory pipeline today. Almost 3,000 MW of additional generating capacity have been approved and are under construction. The State should identify and take appropriate steps to make its regulatory processes as efficient as possible and to ensure that plants in the planning stages—clean efficient state-of-the-art plants--are built.

Transmission upgrades in strategic locations cal also improve reliability. On June 14th the Bay Area experienced black-outs despite the existence of sufficient power sources existed in other parts of the State. Both the Bay Area and San Diego have very old transmission systems coupled with very few lines into the areas. In peak times, those transmission systems are prone to congestion like car traffic becomes backed up on bridges. If problems occur on three of four lanes of a bridge, traffic backs up and only a trickle of traffic can make it over the bridge. Allowing traffic to flow smoothly over all lanes of a bridge, or adding bridges, will reduce congestion. Adding transmission is a complex and costly endeavor, with perhaps longer lead-times than plant construction, so we do not address specific proposals here.

Some argue that transmission facilities owned by municipal utilities need to be integrated into the ISO structure. Municipal utilities built transmission lines to serve their own customers. The intricacies of combining municipal transmission with investor-owned utility transmission are perhaps even more complex than building additional capacity. Moreover, in many if not most instances, contracts exist between the municipal utilities and the ISO which enable the use of all lines in any event.

We suggest that the immediate focus be placed on upgrading key transmission infrastructure into constrained regions rather than on arguing about the particulars of separate systems that are already contractually, economically and physically linked. Upgrading current transmission infrastructure, especially targeted in areas that are the most constrained, can help prevent blackouts by allowing available power to flow to those areas of the State where it is needed.

### *4. ELECTRICITY PRICING REFORM IS ESSENTIAL*

The events so far this year demonstrate that the mechanism for pricing electric energy in California is broken and that the state must reclaim some authority to protect California consumers. The state must address two pricing issues: pricing authority and pricing philosophy.

**Pricing Authority**. As a result of restructuring, the FERC sets prices for the transmission component of the electric bill, in Participating Transmission Owner rate cases and ISO tariffs. The electric energy component of the bill is establish by the PUC, but reflects a pure "pass-through" of wholesale electricity prices. While such a pass-through is required for transactions in wholesale markets, it may not be required for that portion of electric consumption which is provided by power plants owned by PUC-jurisdictional utilities, or under long term contracts with PUC-jurisdictional utilities. The PUC should reconsider whether the wholesale "pass through" approach to setting the electric energy component of the bill.

The pass through of extremely high wholesale prices constitutes a critical issue for California. Under federal law, the PUC has little discretion to refuse to through costs utilities pay for power in wholesale markets. This limitation makes reform of wholesale markets and wholesale supply relationships absolutely essential. California must work with the FERC to bring about meaningful reform in the wholesale market until the supply-demand relationship has eased to the point where competition can really exist.

In the interim, California should legislate changes in how the system is governed. We recommend that the boards of the ISO and the PX should be comprised of members who are appointed by the Governor or other lawmakers, rather than comprised of "stakeholders." No member should have a conflict of interest. Moreover, the law should be modified to provide that the duty of the boards is to promote the interests of the State of California, its consumers and economy. Moreover, ISO deliberations should be public and the information it has should be available to state agencies for review and evaluation, consistent with relevant confidentiality protections. The authority of the EOB to oversee the ISO's operations and decision-making should also be clarified. State lawmakers should also consider whether the PUC or the EOB should have authority to sanction power plant owners, electricity sellers or scheduling coordinators for violations of the law and rules, rather than requiring the state to initiate lengthy and cumbersome civil action.

**Pricing Philosophy**. A substantial proportion of the electricity consumed in California will come from transactions in wholesale markets. The philosophy embodied in the restructuring experiment is that individual customer bargain and sale should establish electricity prices. The PX and ISO wholesale markets exhibit substantial returns to scale and economies of scope and integration that may make this philosophy irrelevant. The PUC should explore means whereby customers can aggregate their loads to levels that would enable them to participate in wholesale power markets where it is in their interest to do so. In the meantime, the traditional utility obligation to serve should be clearly understood to require utilities to purchase energy on an aggregated basis on behalf of their customers with a high degree of diligence and with the objective of assuring reasonably priced electricity.

Exposing consumers to spot market prices where no market exists or where the market can be manipulated to the benefit of sellers is both inefficient and inequitable. Customers who want access to real-time prices should have the opportunity to obtain metering and other equipment on a voluntary basis. However, the state should not impose metering on customers for whom metering will mean only much higher bills, primarily small customers in warm climates.

Customers pay bills that are based on the level of customer usage. The most effective response to high rates is to reduce usage. Pricing policy should provide incentives to conserve and the state should fund programs to help customers conserve.

In addition to providing opportunities for customers to aggregate load to make electricity purchasing more effective, the PUC should provide businesses with an array of pricing and service options that enables them to manage the electricity portion of their cost of doing business, while assuring them the level of service reliability that meets their respective needs. For business customers, this may entail calibrating price and level of service much more precisely than has been the practice under a system of average rates. It should also include programs to evaluate and deploy site-specific technologies, including generation, which will assist businesses in managing their electricity usage.

High electric prices are particularly burdensome for low income and senior customers. The PUC should investigate ways of protecting low income and senior customers from the immediate effects of high rates and, if high rates persist, reconsider the discounts offered under the CARE program.

## Conclusions

In sum, the state has many options for addressing the current problems in the electricity industry. We recommend the Governor, state agencies, and the California legislature work together to assure California's consumers, businesses and economy get the benefits of clean, safe, reliable electricity, and that the state purse problem-solving pragmatically and expeditiously.

## NOTES

[1] These estimates do not reflect the potential for distributed generation.
[2] Source: California Energy Commission.
[3] The PUC regulates investor-owned utilities. Municipal utilities (for example, Sacramento Municipal Utility District) and irrigation districts (for example Imperial Irrigation District) are self-regulating public agencies.
[4] The Biennial Resource Plan Update, I.89-07-004.
[5] PUC Decision (D.) 95-12-059.
[6] Statutes of 1996, Chapter 854, Brulte.
[7] Competition Transition Charge.
[8] PUC Decision (D.) 99-05-051.
[9] The ISO combines the control areas of PG&E, SCE and SDG&E; reserve margins are calculated on an ISO-wide basis.
[10] "Notice to Market Participants", ISO, undated.
[11] It should be noted that in order to maintain a reliable transmission system the WSCC developed Control Performance Standards that require each control area, such as the CAISO, to monitor its frequency every ten minutes. The average for each six 10-minute periods during the hour must be within specific limits as defined by the North American Electric Reliability Council (NERC). For June 13th the CAISO had 29 Control Performance Standards (CPS2) violations of which 17 were attributed to uninstructed deviations. The CPS2 violations are still under investigation and could result in the WSCC assessing monetary penalties to the CAISO. The CAISO will provide further information as it becomes available.
[12] PG&E's previous all-time high peak load was 23,100 MW.
[13] The customers that were shed include commercial, industrial and residential customers.
[14] The rotating outage block system has undergone little analysis or review in decades, and is ripe for revisiting. After being used for the first time ever on June 14, the system was criticized as being potentially unfair to low-income neighborhoods (no evidence of such unfairness was uncovered in a preliminary PUC staff analysis), and inefficient in its operation. PG&E inadvertently blacked out at least one critical facility – the Good Samaritan Hospital in San Jose.
[15] This estimate applies the wholesale spot price of energy, as published by the PX, to the total volume of energy consumed by retail customers of the State's investor-owned utilities and by consumers who have opted to buy their energy from third parties (electric service providers or ESPs).
[16] Utility bills are comprised of a rate for transmission service, which is regulated solely by FERC, and for distribution service, which is still regulated by the PUC and for "generation" which is the rate that reflects the wholesale power market that has been restructured.
[17] Nantahala Power & Light Co. v. Thornburg, 476 U.S. 953, at 970; 90 L.Ed.2d 943; 106 S.Ct. 2349 (1986)
[18] Public Utilities Code Section 739 and PUC Decision (D.) 89-09-043.

[19] The information refers to prices in the Power Exchange's Day-ahead market.
[20] Source: Electricity Oversight Board.
[21] San Francisco Chronicle, July 27, 2000, page A8.
[22] The federal appeals courts have not unanimously endorsed this approach.
[23] The resistance of the ISO and wholesale generators to disclosure of information about power plant operation or market behavior may be unlawful to the CPUC or EOB. The Federal Power Act explicitly provides that a state commission may examine the "books, accounts, memoranda,, contracts, and records…" of an electric utility or an exempt wholesale generator selling to an electric utility or an associate or affiliate of an exempt wholesale generator, "…wherever located, if such an examination is required for the effective discharge of the state commission's regulatory responsibilities affecting the provision of electric service, subject to appropriate restrictions on subsequent disclosure by the commission. 16 USC section 824(g). Any attempt to resist disclosure of power plant operations data, including its relevance to market behavior, on the basis of an ISO tariff provision approved by FERC is undermined by the Federal Power Act's provision precluding commission jurisdiction over "facilities used for the generation of electric energy…." 16 USC section 824(b)
[24] Power plant names and capacities confidential per ISO.
[25] PUC staff study.
[26] Source: City of Santa Clara
[27] Source: Independent System Operator
[28] Southern California Edison Company, et al., (1995) 70 FERC ¶ 61, 215, at p. 61,677.
[29] "Digital Economy 2000", US Department of Commerce June 2000
[30] See, for example, "Electricity Restructuring: Deregulation or Reregulation, February 2000, by Severin Borenstein and James Bushnell.
[31] PUC staff study.
[32] Ibid.
[33] Public Utility Regulatory Policy Act (PURPA) 16 U.S.C. §2601 et seq.
[34] The Public Benefit of California's Investment in Energy Efficiency, Mark Bernstein, Robert Lempert, David Loughran, and David Ortiz, MR-1212.0-CEC, 2000.
[35] Cal. Pub. Res. Code §§ 21000 et. seq.
[36] 42 U.S.C. §§ 7401 et. seq.
[37] Pub. Res. Code §21080(b).
14 Cal. Code Reg. §15269.
[38] Western Mun. Water Dist. v. Superior Court,187 Cal.App.3d 1104 (1986), Castaic Lake Water Agency v. City of Santa Clarita, 41 Cal.App.4th 1257 (1995).
[39] Cal Health and Safety Code, §§39002, 40001.
[40] California Almanac of Emissions and Air Quality, Air Resources Board (1999).
[41] Market Surveillance Committee Report, July 6, 2000.
[42] See "Electricity Restructuring: Deregulation or Re-regulation?" page 9, February 2000.